Pursuant To Section 10 Act 61

AN ACT RELATING TO RENEWABLE ENERGY, EFFICIENCY, TRANSMISSION, AND VERMONT'S ENERGY FUTURE.

Report to the Legislature

January 31, 2006

Respectfully submitted by:

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Report Pursuant to Act 61 Section 10.(a)(1)

Electricity Clearing Price Impacts from Efficiency and Renewables

Introduction

In 2005, the Vermont General Assembly passed Act 61 asking that the Department of Public Service report to the Committees of the Vermont General Assembly on the effects of energy efficiency and renewable energy resources on the market clearing price and its implications for Vermont. This report summarizes our response to this request.

The request made by the legislature highlights a complex and challenging issue. The factors that influence these impacts are dynamic. Significant changes in the underlying assumptions about natural gas or oil prices, or any significant change to the character of the resource mix could significantly change the estimated of impacts.

As our analysis will show, energy efficiency and most renewable technologies tend to reduce the wholesale market clearing price in the region. The range of impacts are presented below, but may result in an annual average reduction of $0.51 $/MWh[1] for programs that reduce load by an average of 100 MW across all hours of the year (8760 hours). These impacts are not insignificant when considered across the energy totals that are cleared through the ISO-NE market. For the approximately 132 TWhs of electricity in the New England region that may be impacted by the reduction, the value of the price reductions to consumers amounts to roughly $67 million per year.

The policy makers, however, should be circumspect in drawing policy implications from these results. The impacts presented below apply to roughly a 3-5 year period. Efforts to suppress the clearing price in the short term have the potential to affect or displace future investments that might have a similar impact. Because Vermont remains dependent on largely embedded contracts and resources through 2011 (for roughly 80% of its resources), the impacts on Vermont from price suppression associated with these estimates are roughly 1/5th that of most of the region.

Background on the Vermont's Situation in Relation to the Regional Wholesale Market for Electricity

While Vermont remains a regulated and vertically integrated electric utility environment, most of the region has moved toward competitive markets and retail choice. Approximately 60% of the retail rate (i.e., the cost of providing service) in Vermont is the cost of the electricity purchased for generation services that in the future could be replaced by resources in the competitive wholesale regional marketplace.

The regional wholesale market for electricity was established in 1997. Significant changes to the regional wholesale electricity market took place in 2003, when the region converted to a Standard Market Design. A central feature of this market is the concept

[1] This assumes an annual average gas price of $10/mmbtu.

of the spot market price for electricity. Within the regional market, all electricity resources are bought and sold and a market clearing price is set after a competitive auction or stacking of the resources. While there are few limitations on the bidding, economic theory suggests that resources will tend to be bid based on their marginal costs of operation. The clearing price that bidders receive is based solely on the price of the last bid to be accepted by the ISO, adjusted for locational costs (losses and congestion).

Like any market, the wholesale price for electricity (i.e., the spot market price for electricity) is set at the intersection of the supply curve (the upward sloping stacking order of bids to deliver electrons to the grid) and the demand curve (the downward sloping stacking order of loads reflecting demand). Again, like other markets, the spot market price can change due to a variety of forces. And indeed, the spot price has proven, at times, to be extremely volatile. Most of the volatility, as one might expect, occurs at the upper range of the supply curve during peak periods. Recognizing these influences, the Vermont General Assembly asked the Department of Public Service to estimate the impacts of two categories of resources on the spot market clearing price. The Vermont legislature asked about the price impacts of an increase the delivery of aggressive energy efficiency or renewable resources.

It should be pointed out that the clearing price impacts under review here are not unique to energy efficiency or renewable resources. Any resource change that has the effect of shifting the stacking order of supply in relation to demand will have a similar impact on price. We are highlighting the effects of energy efficiency and renewable in response to the question presented in Act 61.

<u>Background Economic Issues and Price Suppression</u>

The Vermont General Assembly requested a report concerning energy efficiency and renewables resource impacts on the wholesale market clearing price. In the context energy efficiency and renewables, the ratemaking and taxing authority of government offer the potential to correct for market imperfections to the benefit of consumers. They also hold the potential to drive resource commitments beyond sustainable levels, to the detriment of consumers. Actions taken to suppress what consumers pay for electricity create excess costs elsewhere that eventually find their way back to the consumer.

Actions taken to address the price suppression benefits revealed here are not without real costs. At the margin there is almost always more opportunity for price suppression with apparent value to consumers in excess of out-of-pocket expenditures or subsidies (that ultimately are borne by consumers). There are balancing considerations that the underlying theory can help inform.

It is also helps to recognize that while the short term consumer perspective argues in favor of interventions to lower prices, strategies to do so may serve to displace future resource decisions that would lead to a similar or even better result for price levels in the future. This suggest an emphasis should be placed on sustainable strategies, generally with a foundation in real economic costs.

La Capra Analysis and Estimates

La Capra Associates was retained by the Department to assist it in responding to this legislative request. La Capra Associates identified the impacts of energy efficiency and renewables on the wholesale price of electricity by developing an estimate of the supply stack of resources (supply curve) for the region. The supply stack, however, is dynamic and will change by season, and over time with the addition of new resources. So too will estimates of impacts on wholesale prices of energy efficiency and/or renewable energy resources.

The price impact of energy efficiency and new renewables are highly dependent on the prices of fuels. With the present volatility of fuels, particularly natural gas, La Capra's methodology provides estimates of impacts that are, for the most part, independent of fuel price changes. La Capra estimated the impacts of energy efficiency and renewables on the market clearing price by defining the supply stack according to "implied heat rates" rather than actual bids. Reductions in prices are a result of reductions in the average marginal heat rate, with the greatest impact occurring in periods where the marginal heat rate is highest. In doing so, La Capra allows us to estimate the market clearing price impacts for different assumptions about natural gas prices.

In the examples below, estimates of average price suppression are presented for $6/mmbtu, $8/mmbtu, and $10/mmbtu gas prices (as of December 30, 2005, the wholesale gas price was about $11/mmbtu). Table I below can also be used to calculate price suppression from load reduction measures that affect only certain periods or seasons, such as load response programs that impact peak summer hours.

Table 1: System Price Reductions Per 100 MW of Load Reduction Annually and by Season and Period

Annual Change	Annual Price Impact per 100 MW of Reduction ($/MWh)		
Gas Prices ($/mmbtu)	Off-Peak	On-Peak	Average
$6.00	($0.15)	($0.48)	($0.31)
$8.00	($0.21)	($0.64)	($0.41)
$10.00	($0.26)	($0.79)	($0.51)

Seasonal Change	Energy Price ($/MWh)			
	Gas Price @$6.00/mmbtu		Gas Price @$8.00/mmbtu	
Season	Off-Peak	On-Peak	Off-Peak	On-Peak
Winter (Dec-Feb)	($0.08)	($0.20)	($0.11)	($0.27)
Shoulder (Mar-May, Oct, Nov)	($0.16)	($0.34)	($0.21)	($0.45)
Summer (Jun-Sept)	($0.20)	($0.85)	($0.27)	($1.13)

Energy Efficiency and Renewables

Numerous efficiency programs and resources exist that impact the clearing price during peak and off-peak periods differently. Renewable resources are typically either intermittent or baseload in character. DSM resources have individual load shape. Table 2 provides a guide for the types of resources and the potential impact on seasonal and peak/off-peak periods. The calculated price is weighted based on the impact periods related to each measure or resource. For resources that are either used sporadically, such as appliances, or are intermittent or baseload units with an associated capacity factor, these resources are not directly linked to time-of-day or season; thus, an average megawatt measurement is assumed.

Each estimate in Table 2 assumes a 100 MW reduction in the load supplied by each resource. This is a large amount for Vermont, but not for the market as a whole. However DSM and renewable energy in other states will benefit as well, so it is reasonable to look at these amounts if Vermont does its part.

Table 2: Price Suppression for Select Energy Efficiency and Renewables Programs

	Annual Price Impact per 100 MW of Reduction ($/MWh)		
Energy Efficiency	**Gas Price @$6.00/mmbtu**	**Gas Price @$8.00/mmbtu**	**Impact Periods**
Residential Air Conditioning	($0.06)	($0.08)	Summer (600 Hours) On-peak
Residential Heat Pump	($0.09)	($0.12)	Summer (600 Hours) and Winter (1500 Hours) On-Peak
Compact Fluorescent Lighting	($0.04)	($0.05)	3 Hours/Day
Appliances	($0.31)	($0.41)	All (aMW)
Commercial HVAC	($0.16)	($0.21)	Summer and Winter On-Peak
Motors	($0.23)	($0.30)	On-Peak
Commercial Lighting	($0.23)	($0.30)	On-Peak

Renewables	Gas Price @$6.00/mmbtu	Gas Price @$8.00/mmbtu	Impact Periods
Solar	($0.11)	($0.15)	On-Peak (50%)
Biomass	($0.31)	($0.41)	All (aMW)
Wind	($0.29)	($0.39)	See Shape (aMW)
Fuel Cells	($0.31)	($0.41)	All (aMW)

Implications for Vermont

Across the New England region, energy efficiency resources and/or renewable resources will help reduce price and potentially volatility of the wholesale market clearing price available to Vermont utilities. In contrast, the potential impacts on Vermont will be muted by our significant share of generally low cost embedded resources that exist (roughly 80% are fixed through 2011). A disproportionate share of the Vermont power mix is tied to long term power contracts (e.g., with Vermont Yankee and Hydro–Quebec ending in 2012, and roughly 2015 respectively). The remaining resources, including those owned by Vermont utilities (hydro and McNeil biomass generator), are the subject of other long term power contracts, or include some limited level of exposure to the market. Vermont utilities have also showed renewed interest in limiting exposure to the wholesale power markets by looking to purchase renewable resources.

The practical effect of the embedded resource mix is that Vermont utilities and consumers face limited exposure, at least currently, to the wholesale electricity market during the reference period of this analysis (i.e., 3-5 years). The results of this analysis should therefore be viewed with an understanding that Vermont is buffered from exposure to wholesale power price effects estimated here, more than the rest of the region. Consequently Vermont consumers benefit less from regional actions to reduce prices. Estimating impacts beyond the 3-5 years is especially challenging. However, if both demand and supply conditions remain largely as they exist today, these estimates may also be relevant in 5 years.

Impacts on Fuel Price Variability

La Capra was also asked to estimate the impacts of energy efficiency and renewables on fossil fuel prices.

Energy efficiency and renewables can mitigate the risk associated with fossil fuel price variability in three ways. (1) less electricity generation from fossil-fired generators means less fuel consumption; (2) less fuel demand translates to more available supply for heating loads; and (3) renewables in a supply portfolio provides a hedge against volatile fuel price movement for that portion of the portfolio.

Nearly all of the new electric generation built in New England over the last decade, amounting to more than 9,000 MW, is fueled by natural gas. Natural gas is expected to account for 49% of our electric energy by 2010. By virtue of our location (i.e., being far from gas sources) and associated transportation constraints, New England sees significant increases in natural gas prices during cold weather conditions.

During extreme winter conditions small changes in natural gas consumption can have a disproportionate impact on natural gas prices, particularly in the transportation constrained New England region. Because natural gas is often the fuel used by the marginal unit in New England, reductions in natural gas prices can lead to reductions in electricity prices as well. This impact stands above those captured in the earlier analysis. One study suggests that a 1% reduction in gas demand could lead to a long-term reduction in wellhead prices of between 0.75%-2.5%.[2]

[2] Ryan H. Wiser, *Managing Natural Gas Price Volitility and Escallation: The Value of Renewable Energy*, LBS, March 23, 2004.

The fuel saved from reductions in load, unlike electricity, can be diverted to storage to meet increasing heating demands during the winter months. This storage capability helps to buffer peaks. Any demand suppression helps to buffer natural gas price extremes and the resulting impact on electricity prices.

Conclusions

Our estimates suggest that DSM creates an annual average reduction of $0.51 $/MWh for programs that reduce load by an average of 100 MW across all hours of the year (8760 hours). These impacts are significant when considered across the energy totals that are cleared through the ISO-NE market. For the approximately 132 TWhs of electricity in the New England region that may be impacted by the reduction, the value of the price reductions to consumers adds approximately $67 million per year.

The price impacts that were viewed by La Capra reflect the impacts on price over a relatively short time frame. However, any significant change in the resource mix, demand conditions, or fuel price changes could alter these estimates. If conditions remain relatively stable over time, then these estimates may have a more lasting impact.

Not all of these price effects are strictly "costs" from an economic perspective. They reflect lower prices, and therefore costs to ultimate retail consumers in the short term (estimated to be 3-5 years). From a supplier perspective, however, they impact perceptions of investment opportunities. Such perceptions ultimately translate into resource decisions that have implications on prices in the long term. In effect, short term investments or actions can serve to displace longer term investments or actions that, over time, can create similar results.

The benefits of programs that lower wholesale electric market prices reinforce policies encouraging the development of these resources, when the underlying economics are favorable (i.e., when benefits exceed costs). Some caution is warranted in interpreting these impacts and the associated policy implications. The majority of the price benefits to retail consumers reflect short term changes in prices and can contribute to the displacement of resources with longer term potential.

Report Pursuant to Act 61 Section 10.(a)(2)

Potential for Aggressive Regional Approach to Energy Efficiency and Renewables to be Integrated with Regional T&D Planning and Greenhouse Gas and Air Emissions Reduction

Introduction

The Vermont General Assembly requested that the Department of Public Service evaluate the potential for integrating an aggressive regional approach to energy efficiency and renewables to with regional T&D planning and greenhouse gas and air emissions reduction efforts. The potential integration of these objectives raises a number of complex issues involving estimates of potential, mechanisms for integrating energy efficiency and renewables with transmission planning, and mechanisms for integrating regional initiatives directed at air emissions and greenhouse gas emissions.

The Department evaluated the legislature's to the legislature's request in four ways. First, we reviewed the literature for any studies of the potential for efficiency and renewables in the region. The Department is also updating its own analysis is of efficiency potential for Vermont.[3] Second, the Department summarized the many and varied approaches to promoting renewables within the region. These include broad federal initiatives, state initiatives, utility initiatives, and regional programs of ISO-NE.[4] Third, the Department reviews the existing ISO-NE planning process from its Resource System Plan. Finally, we suggest regional approaches to further promoting energy efficiency and renewables.

In 2001, the New England Governors and the Eastern Canadian premiers issued a Climate Change Action Plan, which calls for the reduction of greenhouse gases to 10% below 1990 levels by 2020. The Regional Greenhouse Gas initiative ("RGGI"), represents an ad hoc cooperative effort to further progress toward these objectives through the a cooperative effort of governors in 9 states (although only 7 signed on in December of 2005.) With final plan agreement reached in 2005, Vermont is now responsible for adopting the enabling regulatory framework laid out in this plan.

Vermont is in a unique position with respect to the RGGI initiative. Vermont has little fossil fuel generation that will require the RGGI emissions credits. Nevertheless, Vermont consumers will be impacted by RGGI through the through initiative's effects on the regional wholesale price levels. However, because Vermont continues to enjoy the benefits of large embedded resources and contracts, those impacts should be small until 2012. In the mean time, Vermont can benefit from the program by directing funds

[3] The analysis is not provided in this report because it is still underway. This analysis will be available in March/April of 2006.

[4] Understanding initiatives to date provides both a helpful context and can help inform the development of new approaches that will either complement existing approaches, or provide more effective and sustainable strategies.

collected from Vermont's allocations of allowances to consumers and projects that are consistent with the goals of RGGI, including further development of an ongoing clean resource mix. On a regional basis, Vermont should join other states in the region to ensure the success of the RGGI initiative.

I. Potential for Energy Efficiency and Renewables in Vermont and in the Region

Energy Efficiency

With respect to the potential for energy efficiency, the Department is preparing an estimate for Vermont by updating an estimate from January 2003. We anticipate the preliminary results of this analysis will be available in late March. We intend to update our estimates of potential with that of other studies to develop a more comprehensive picture of potential in the region. Table I shows the potential for the region based on recent studies. Most of the neighboring states have shown a technical potential[5] that ranges from 21 to 31% and a Max. economically achievable potential[6] of 13 to 25% of existing load levels.[7]

The New England Energy Partnership ("NEEP") is a nonprofit organization devoted to promote energy efficiency in homes, buildings and industry, through regionally coordinated programs and policies.[8] NEEP has estimated the efficiency potential for New England equates to a reduction of 17,103 GWhs by 2008 and a reduction of 34,375 GWhs by 2013.[9] This compares with ISO-NE forecasted load levels for New England of 140,700 GWhs in 2008 and 150,785 GWhs in 2015.[10] Almost 2/3rds of the potential (63%) is available from the commercial and industrial sectors. These estimates suggest economically achievable savings over time of roughly12 and 24% respectively.[11] According to NEEP, the full exercise of potential in the region could reduce load levels in 2013, to levels that existing in 1993.

[5] *Technical* potential is defined as the complete penetration of all measures analyzed in applications where they were deemed to be technically feasible from an engineering perspective.
[6] *Economic* potential refers to the technical potential of those energy conservation measures that are cost-effective when compared to supply-side alternatives.
[7] Relative to current load levels (roughly 134,000 GWhs), reductions of 13 to 25% in New England would be equivalent to between 17,762 GWhs and 34,158 GWhs, equivalent to roughly twelve 200 MW baseload generators.
[8] See, http://www.neep.org/. The NEEP is also working with states to foster energy efficiency standards for the region.
[9] See, ISO-NE forecast details at, http://www.iso-ne.com/trans/celt/fsct_detail/2005/isone_2005_forecast_data.xls
[10] Id.
[11] The fact that the savings levels reported by NEEP are similar to those of the other reports and studies is more than coincidence. NEEP relied on these other reports in developing their estimates of potential. http://www.neep.org/files/NEEP_Achievable_Potential_Presentation_UPDATED.ppt

Table I[12]

Summary of Electricity (or All Fuels) Savings Potential Studies - US										
Area(s) Covered	Type of Savings Potential	Year Completed	Author(s)	Estimated Consumption Savings as % of Sales				Estimated Summer Peak Demand Savings as % of Total Capacity	Years to Achieve Estimated Savings Potential	Comments
				Res.	Comm.	Indus.	Total			
Connecticut	Technical Max. Technically Achievable Max. Economically Achievable	2003	GDS Associates/ Quantum Consulting	21% 17% 13%	25% 17% 14%	20% 15% 13%	24% 17% 13%	24% N.A. 13%	10	Also includes results for Southwest CT region
Massachusetts	Max. Economically Achievable	2001	RLW Analytics / SFMC	25%	16% - C&I		N.A.	N.A.	5	Excludes non-utility impacts & low income savings/sales
New York	Technical Economic	2002	OEI / VEIC / ACEEE	37% 26%	41% 38%	22% 16%	37% 30%	N.A.	10	Also 5- and 20-year scenarios
Vermont	Max. Technically Achievable	2002	OEI / VEIC	30%	32% - C&I		31%	37%	10	Includes fuel switching; also 5-year scenario
VELCO	Max. Technically Achievable	2002	OEI / VEIC	18%	17% - C&I		17%	23%	10	Excludes measures with little peak demand, that require regional coordination, and emerging technologies; includes fuel switching; also 5-year scenario

Technical potential is defined as the complete penetration of all measures analyzed in applications where they were deemed to be technically feasible from an engineering perspective.

Economic potential refers to the technical potential of those energy conservation measures that are cost-effective when compared to supply-side alternatives.

Maximum Technically Achievable potential is defined as the amount of technical potential that could be achieved over time under the most aggressive program scenario possible.

Maximum Economically Achievable potential is defined as the amount of economic potential that could be achieved over time under the most aggressive program scenario possible.

Budget Constrained potential refers to the amount of savings that would occur in response to specific program funding and measure incentive levels.

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[12] Estimates compiled courtesy of VEIC.

Renewables

The Department is in the process of assembling estimates of renewable resource potential for New England. Access to renewables exists primarily within Vermont, in New England, and New York. Considerable potential resource potential also exists in Canada.

Vermont's largest landfill in Coventry Vermont is now being used to generate electricity for WEC. Additional potential appears limited to small scale facilities and additional capacity at existing sites. For landfill gas methane in the New York and New England region, there is roughly108 MW of existing capacity and 104 MW of potential.

In New England, the greatest potential for commercially viable renewable energy is with biomass and wind.[13] Conventional hydro generation is considered a mature technology.[14] Hydro energy from Vermont-based facilities is likely to remain stable or decline over time with relicensing. Kinetic hydro based power provides an alternative to traditional hydro without the environmental concerns associated with stream diversion. However, Hydro-Quebec has over 1500 MWs of additional generation capacity under construction.[15]

In Vermont, there are potentially 759 miles of ridgelines in Vermont with potential for some for utility scale wind projects in Vermont. The practical potential is, however, constrained by many factors including siting concerns. In early 2005, figures provided to the DPS from Renewable Energy Vermont indicated a wind potential in Vermont of approximately 137 MW (providing up to 6% of our energy needs).

Tenders issued by Hydro-Quebec Distribution reveal that there is at least 1000 MW of wind potential available through independent power producers in Quebec. Another 2000 MW of wind potential also is being sought within the region. Roughly 330 MW of wind potential already exists to serve Canada and about 100,000 MWs of wind potential exists within 25 kilometers of existing transmission lines that are reported to be economically viable in the short and long term (equivalent to roughly 35,000 MW of baseload generation).[16]

A study prepared for the Department in 2000 estimates the potential from farm methane to be roughly 30 MW. Biomass may hold the greatest potential for Vermont. At present Vermont has two utility scale generators; the McNeil station at 52 MW and Ryegate at 20

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[13] See, for example, the DOE/EIA's assessment of potential. http://www.eia.doe.gov/emeu/reps/rpmap/rp_new-eng.html

[14] Additional potential for traditional hydro was identified in the 1980s and could be economic if price levels in the region could sustain the investments. Even at elevated price levels, however, the projects would face formidable efforts in the permitting process.

[15] HQ's Eastmain 1 project is scheduled for to be in service in early 2007. The project will contain three generating units with an installed capacity of 480 MW. The generating station will have an average annual output of 2.7 TWh, roughly half of Vermont's annual consumption. Other projects under construction include Toulnustouc (524 MW, 2.7 TWhs), Péribonka (285 MW, 2.2 TWhs), Chute-Allard and Rapides-des-Coeurs (138 MW).

[16] See, http://www.ecologicinvestor.com/news/readfullnews.asp?NewsID=563.

MW. Another 20 MW facility has been announced for Ludlow. Biomass facilities can provide baseload generation, depending on market conditions.[17]

II. Existing State and Federal Incentives to Promote Energy Efficiency and Renewables within the Region

New England relies on a variety of state approaches to promoting energy efficiency and renewables. Table I shows the list of policies and programs designed to help promote renewables or to address market barriers. Table II shows the various financial incentives offered by the states in New England.

[17] Biomass generation, however, faces its own challenges associated with availability and transportation of the resource. Effective transport typically requires local rail and/or an ability to move substantial quantities with trucks. It also suffers from some environmental disadvantages. Wood contains sulfur and nitrogen, which yield SO_2 and NO_x in the combustion process. However, the rate of emissions is significantly lower than that of coal-based generation. Zia Haq, *Biomass for Electricity Generation, USDOE/EIA. http://www.eia.doe.gov/oiaf/analysispaper/biomass/*

Table I[18]

Database of New England States Incentives for Renewable Energy Rules, Regulations & Policies

State/ Territory	Disclosure	RPS	Net Metering	Inter- connection	Contractor License	Equipment Certification	Access Laws	Green Power Purchase	Required Green Power
Connecticut	S	S	S	S	S			S	
Maine	S	S	S			S	S	S	
Massachusetts	S	S	S	S			S	1-L	
New Hamp.			S	S			S		
Rhode Island		S	1-U	S			S	S	
Vermont	S	SPEED	S	S				2-U	

S = State **L** = Local **U** = Utility

[18] DSIRE. 1/10/05, See, http://www.dsireusa.org/, modified only Vermont.

Table II[19]
State Incentives for Renewable Energy
Financial Incentives

State/Territory	Personal Tax	Corporate Tax	Sales Tax	Property Tax	Rebates	Grants	Loans	Industry Recruit.	Leasing/ Sales	Production Incentive*
Connecticut				S	S	3-S	3-S			
Maine					S	S				
Massachusetts	2-S	3-S	S	S	S	2-S				S, P
New Hampshire				S						
New York	S		S	S	3-S, 1-U	S	S			
Rhode Island	S		S	S	2-S	S				S, P
Vermont			S		S	U				U

S = State **L** = Local **U** = Utility/Energy Service Co. **P** = Private

[19] Id.

Most of the New England states have provided funding for the development of renewable electric power sources. This funding is supported largely through system's benefit charges.[20] Four of the New England states and New York have established a renewable portfolio standard to further the development of renewable energy. Only Vermont and New Hampshire have not created a renewable portfolio standard. In its place, Vermont established a target for the development of renewable projects and contracts for Vermont utilities. If the targets are unmet, Vermont will join it neighbors in establishing a renewable portfolio standard in 2013.

Several states in New England and in New York employ the use of renewable development funds, including New York, Massachusetts, and Rhode Island.

As noted further the discussion of tradable credits for efficiency, Connecticut and Pennsylvania are pursuing this structure independent of one another.

Efficient pricing mechanisms such as time-of-day, dynamic or peak pricing are important tools Vermont can employ in its search for greater energy efficiency. The Ontario provincial government has found the potential for these mechanisms to be sufficient to mandate that by 2010 all Ontario electric consumers should be receiving dynamic pricing. Dynamic pricing allows consumers to know exactly what electricity costs throughout the day. The cost of providing electric power varies with the time of day and season. With traditional metering and billing methods, most customers are unable to differentiate between the high and low cost periods. Customers typically see one or perhaps two billing rates and only at the end of the month. Without additional price/cost information, they cannot make efficient choices about their energy consumption.

Until recently, many people in the electric power industry did not believe that the majority of consumers (small commercial and residential) would change their consumption even if they did have access to hourly price information. However, a pilot project initiated by the State of California and its utilities has found that residential customers are quite responsive to this information/price changes (California Statewide Pricing Pilot, 2005. Southern California Electric, Pacific Gas & Electric and San Diego Gas& Electric with the California Demand Response Research Center and Charles River & Associates).

Historically, a few large electric customers have had access to a form of dynamic pricing. Having this information allowed them to schedule their most power intensive work at low-cost times of day. Until recently, the technology did not exist to provide comparable information, by practical means, to smaller consumers. However, with the development of advanced meters, dynamic pricing can now be provided to all customers. The cost of these new meters is much higher than the conventional meters but these new meters do not require any visits and provide other efficiencies that lower their overall cost in comparison to conventional meters.

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[20] System Benefits Charges are charges on electric bills used to collect revenues for public benefit programs analogous to Vermont Energy Efficiency Charge used to fund Efficiency Vermont.

Federal Initiatives and the Energy Policy Act of 2005

Federal lawmakers and policy makers have a long list of policies and financial incentives that have been developed to promote the development of renewable resources. Significant initiatives of the past have included the Public Utility Regulatory Policy Act of 1978 require utilities to purchase power from renewable energy developers under must-take provisions at avoided costs.

In recent years, Federal policy makers have offered a variety of incentives, but perhaps most important of these are the Code Section 45 tax credits that are a form of production tax credits. These credits were created by the 1992 Energy Policy Act and extended through the Energy Policy Act of 2005 by providing that the "placed in service date" through December 31, 2007 for facilities qualifying for tax credits, which may include wind, closed-loop biomass, open-loop biomass, geothermal, small irrigation power, landfill gas, and trash combustion facilities.

Under the energy Policy Act of 2005, Congress committed approximately $2.7 billion in tax incentives for energy efficiency/conservation and $2.9 billion in tax incentives for the development of renewable and clean energy technologies. The Act also provides relief from PURPA. The Act removed the “must-take” provisions of PURPA to purchase renewable energy provided that certain accesses to market conditions are met. One area in which the EPAct is closely tied to the actions of states is in the development of time-of-use metering and time-of-use rates. As a condition of PURPA relief, EPAct 2005 requires that a standard of consumer access to real time metering and available rates to all consumers be adopted. Vermont intends to adopt the standard, likely through a rulemaking proceeding.

EPAct also modified the efficiency standards for 15 new products.

III. Potential for Aggressive Regional Initiatives Related to Energy Efficiency and Renewables through T&D Planning

ISO-NE

The legislature’s question, as applied to transmission and distribution, implies that the New Englan ISO’s planning process can provide an avenue for aggressive regional initiatives. Absent other state or federal initiative, the most suitable forum for aggressive regional initiatives is likely with the New England ISO (ISO-NE).

Current Planning

ISO-NE planning process is complex and attempts to integrate the requirements of the transmission system for reliability, with generation and loads. With the development of the RSP process, the ISO is working toward the development of a system that no longer addresses generation and loads as a given, from which the transmission system is planned, but also as resources to supplement the requirements of the grid.[21] As ISO-NE puts it in their Resource System Plan:

> The critical inputs to the planning process are load forecasts, projections of generation and distributed resources that reduce load, and an assessment of the performance of the overall system, including the transmission system that moves power to where it is needed. Also vital to the planning process is to account for new supply and demand-side resources including the necessary lead times for permitting and construction.[22]

ISO-NE is responsible for ensuring the reliability and adequacy of the transmission system. The Planning Advisory Committee and the NEPOOL Reliability Committee, engage in various stakeholder meetings over the planning cycle. The planning processes begins with the planning criteria of the system. These include establishing the reserve margin requirements[23] and deterministic allowance for contingencies (generally referred to as the "N-2" criteria).[24]

The ISO planning process establishes the key assumptions for installed capability. The process is for a 10 year period (including state forecasts out 10 years) and incorporates certain assumptions about "tie benefits",[25] an absence of constraints within the system, and retirements.[26] In contrast, the ISO's operable capability analysis relies on a deterministic scenario analysis to ensure the day-to-day reliability of the system after considering the extreme weather conditions and other variables. The compatibility between the probabilistic approach for installed capability and the deterministic approach to operable capability is a matter under review by the Planning Advisory Committee.

Current Assessment

ISO-NE is forecasting energy growth of 1.4 percent and peak growth of 1.5 percent over the next 10 years for the entire New England region. Energy per household is forecasted to rise at a rate of 0.7 percent per year over the coming decade. By its own analysis, ISO-NE concludes that ISO's forecasting capability has consistently under forecasted peak

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[21] As ISO-NE notes in their Plan, "RSP05 is broader in scope than the RTEP reports. For both RTEP and RSP reports, the ISO analyzed the system's capability to reliably serve load over a 10-year period, the need for new resources, and transmission improvements. RSP05 provides additional information on the types of resources needed over the planning period." ISO-NE, *Regional System Plan*, 2005, at 16.

[22] ISO-NE, *Regional System Plan*, 2005, at 15. To date, however, the demand-side resources that ISO-NE has pursued has been limited to demand-response initiatives.

[23] ISO-NE New England uses the NPCC resource planning reliability criterion that requires a power system to have enough installed capacity so that firm customer loads are not disconnected more than 1 day in 10 years (or 0.1 day per year).

[24] OP 19 further stipulates that within 30 minutes of the loss of the first contingency element, the system must be able to return to a normal state that can withstand a second contingency (N-2). This "N-2" constraint is met by maintaining an operating reserve that can increase output when the first contingency occurs. RPS at 56.

[25] Cross-border benefits of uncommitted resources associated with ties to New York, the Maritimes, and Quebec.

[26] The current RSP assumes no retirements over the next 10 years. RSP, 2005, at 19.

loads and is in the process of refining its forecasting methods to ensure more accurate forecasting.[27]

ISO-NE relies on extreme weather analysis in generating its forecast of peak needs. Under weather extremes, the forecasted load over the next 10 years (in 2014) is forecasted to rise by 5,130 MW above the 2005 summer peak (32,050 MW versus the recent peak of 26,922 MW). To put this in perspective, the increase in load for the region is approximately 5 times the Vermont peak load. However, ISO-NE's history of underforecasting peak together with assumptions concerning tie-line benefits,[28] and no retirements in the analysis provides reason for caution, especially given the long lead time requirements for most generation and transmission solutions.

ISO-NE is aware of the uncertain nature of the tie-line benefit and conducts sensitivity analysis in its studies to identify need in the event that the tie-line benefits are either 0 or half the FERC approved 2000 MWs. In its most recent RSP, FERC concluded that additional resources were needed in the region as early as 2006, if tie-line benefits could not be relied upon. According to ISO, the regions that are most vulnerable are Southwest Connecticut and Boston.

Coming capacity deficiencies raises many fundamental concerns. The capacity shortage is especially acute with respect to quick start capabilities and, in relation to state portfolio requirements for renewables, the development of new renewable resources.

Today, the ISO Demand Response programs compensate large electricity users for reducing consumption when market prices are high or demand is high and system reliability is at risk. Qualifying retail loads are eligible to participate in the program. In December 2005, ISO-NE listed approximately 860 assets capable of providing approximately 440 MW of response capability.[29]

Additionally, New England is far too reliant on a single fuel for generation. Roughly 38% of the capacity in the region is dependent, in whole or part, on natural gas for fuel. Roughly 20% of the capacity in the region is dependent solely on gas. During extreme cold periods in the winter, the demand for natural gas as a heating fuel coincides with its use as a source for peak electricity. . And while most natural gas local distribution companies hold firm power contracts for gas transport capability, only about 4,300 MW of electric generation capacity in New England holds firm gas contracts.[30] When combined with the load serving obligations of the natural gas local distribution companies (LDCs) at times of peak demand,[31] the competitive electric generators are

[27] Historically ISO-NE underforecasted peak by applying a constant load factor to its energy forecast. ISO-NE envisions forecasting a declining load factor into the future to correct to the error.

[28] "Tie-line" benefits refer to the benefits associated with relying on unscheduled or committed resources from neighboring control areas that can be relied upon within the New England region during periods where there are shortages of available capacity and energy.

[29] http://www.iso-ne.com/genrtion_resrcs/dr/stats/enroll_sum/2005/261,2,Demand Response (as of December 1, 2005)

[30] Total winter capacity relying only on gas is 7,313 MW, or approximately 22% of winter capacity.

[31] LDC's also enjoy the competitive advantage of potentially passing along the cost to ratepayers.

going to be either forced or financially coerced to yield to the requirements for gas of the natural gas LDCs. This problem will only be compounded by equipment failure and a myriad of other issues that test the ability of natural gas generators to deliver during winter peaks. The cold-snap of January 14-16, 2004 highlighted this problem.

Maintenance requirements and other concerns present challenges for gas generators in the summer. The development of approximately 9000 MW of natural gas generation in neighboring control areas, will only exacerbate an already week position for New England's natural gas electric generators.

Analysis

ISO-NE recognizes the need to address the constraints facing natural gas generation, and the broader issue of fuel diversity. ISO-NE recommends looking toward additional gas transport capability and dual fuel capability. The ISO is looking at increasing the incentives for more 10-minute and 30-minute ready generation capacity in the forward reserve market. It is also examining economic incentives for firm gas or dual fuel capabilities. The ISO is also looking for better alignment of incentives in the forward reserve market to encourage delivery in line with the capability of the units. [32]

Even beyond the development of the dual fuel capability, the ISO recognizes the need to encourage fuel diversity. Here, the ISO points to the potential for "non-market" incentives for the resources, such as through the renewable portfolio standards of states and the demand-side management efforts of states like Vermont paid for through utility rates and revenue streams. While other fuel types can help, coal faces a particular disadvantage with air regulations and the implementation of RGGI. Under the RGGI, non-emitting technologies, including wind, solar and nuclear have a distinct advantage.

Renewable resources have certain advantages and disadvantages in New England. Wind resources appear to be quite significant along the ridgelines of the hills and mountains in western Massachusetts, Vermont, New Hampshire and Maine.[33] However, problems with the siting of these resources is considerable due to the significant view shed. Given the current high energy prices, biomass appears favorable.

The potential for aggressive regional action related to energy efficiency and renewables in the short term, is probably best tied to the actions of ISO-NE. This effort can begin at the ISO with the development of stable and well designed markets for energy, capacity, and ancillary services. Vermont is currently working with load serving entities and other regulators to ensure that the capacity market is well designed and allows for efficient price signals to both producers and buyers, and includes adequate incentives to demand-side resources.

[32] RSP 2005, at 74.
[33] See, DOE/EIA, http://www.eia.doe.gov/emeu/reps/rpmap/rp_new-eng.html

Energy efficiency and renewable resources require market signals that accurately reflect the nature of the resources required. In the past, the demand side resources have been largely ignored and/or disconnected from the retail loads. ISO-NE needs to continue to work with the states to enhance retail consumers' ability to respond to wholesale market conditions. They can do this by providing (1) better and longer term assessments of need, (2) working with states to better target energy efficiency, and (3) working with ISO-NE and neighboring states toward the development of resource parity cost-sharing mechanisms.

Another area in which ISO-NE can foster the development of alternatives is in the planning process. Vermont regulators have long worked with neighboring regulators to encourage ISO-NE to take an aggressive stand with respect to resource parity (e.g., renewables and energy efficiency).[34] ISO-NE responded by changing the Regional Transmission Expansion Plan (RTEP) to the Regional System Plan (RSP) and expanding consideration of the resource options considered. The 2005 RSP identified the immediate need for 1,100 MW of "quick-start" resources. Quick-start resources include load-response programs. The RSP, however, remains a document that is largely focused on maintaining reliability through transmission expansion plans.

There appears to be more room for the RSP to to expand beyond transmission solutions, and, in particular, focus on the opportunity to fully tap customer demand as a resource, whether through load-response or through time-of-use rates that ensure more efficient markets and more and better system reliability. Additionally, ISO-NE should strengthen market mechanisms to recognize the inherent reliability benefit of non-fossil fuel resources with little or no exposure to supply chain disruptions. ISO-NE can also work with the states to encourage more effective targeting of DSM resources where they may offer the greatest potential for reliability benefits.

Conclusions and Recommendations

ISO-NE

ISO-NE is forecasting energy growth of 1.4 percent and peak growth of 1.5 percent over the next 10 years for the entire New England region. New England needs to keep pace with demand while also managing the risk it faces because of its heavy dependency on natural gas. The sufficiency of capacity within the region is also a concern. ISO-NE needs to consider its responsibilities for market development and reliability more expansively to address the long-term needs of the region for fuel diversification. Fuel diversity is fundamental to reliability in New England.

With respect to renewables and energy efficiency resources, the New England states have taken a leadership role. The Energy Policy Act of 2005 adds standards and incentives

[34][2] See, for example, the NECUP letter to ISO-NE, dated February 4, 2003, http://www.necpuc.org/public_filings/document69.doc

that will supplement state initiatives for promoting energy efficiency and renewable resource technologies.

Analysis of New England's the load growth and its corresponding resource needs suggests that Vermont and New England are facing resource shortfalls in the coming years--much more so than were revealed in prior analyses. In relation to the targets that states have set for the region, renewable resources appear likely to fall well short of existing targets.

There are many ways to address this need, but the region would do well to establish stable and robust markets for capacity and energy that are coupled with mechanisms to better foster the development of renewable resources and persistent energy efficiency resources. Included among the specific actions that can be taken by ISO-NE are the following:

> (1) Establish and fund a process for determining eligible generation sites. A centralized, initial siting review could help reduce the time necessary for permitting new generation facilities. This in turn could help to bring much needed new dispatchable and renewable generation, on line faster.
>
> (2) Continue the evolution of market definitions and products to recognize the inherent strengths efficiency as a resource and of renewable technologies as durable and reliable base load services;
>
> (3) Foster transparent transmission planning and neutral resource acquisition by enabling financial compensation of alternatives to transmission by state siting/regulatory agencies;
>
> (4) Develop new strategies for delivering energy efficiency, beyond demand response. These new strategies should be part of the resource mix relied upon to help meet the short and long term reliability needs of the region;
>
> (5) Ensure that regional planning and load forecasting time horizons are sufficient length to anticipate the need for energy efficiency programs in potentially T&D stressed areas;
>
> (6) Coordinate with appropriate state agents to ensure effectively targeted programs. As appropriate, supplement the program activities for demand side management programs to target loads;
>
> (7) Create stronger links between retail demand, wholesale prices and system reliability, by encouraging states to rely on complementary retail rate designs;
>
> (8) Continue to promote the effective use of demand response programs.

One of the fundamental challenges that New England faces with respect to demand-side resources is ***measurement***. ISO-NE has shown a willingness to pursue energy efficiency alternatives where they can be readily measured. Supply resources fair well because output can be measured or metered. New strategies for addressing this hurdle appear to be central to achieving greater reliance on DSM by ISO-NE.

State Efforts

Siting continues to be a major challenge for New England. The states can augment the seven actions listed above by ensuring that the sighting of resources (be they renewables or traditional generation and T&D) be given a fair and timely review. Consideration should be given to the development of pre-approved or limited review sites, that could complement or parallel efforts to accomplish the same for ISO-NE's own permitting review efforts.

The states can play an important role in promoting efficient energy consumption through the use of efficient price signals. This may include reliance on time-of-use rates, dynamic pricing, and critical peak pricing programs. Efforts of the states along these lines can both empower consumers to lower their costs, and reduce the burden on the entire region.

The states can also play a role in working with the ISO or its satellite organizations to ensure that energy efficiency programs are properly targeted.

The issue of resource parity will continue to present a challenge to the region as long as one class of resources is favored in the regional cost sharing of transmission resources. Consideration should be given to allowing resource parity for incentives to be shared among participating states.

Air Emissions

Vermont is in a fairly unique position with respect to the Regional Greenhouse Gas Initiative (RGGI). Within New England, Vermont remains the only state with vertically integrated and fully regulated distribution utilities. Any market implications of the RGGI flow to ratepayers through the cost-of-service. However, the system of allowances granted to Vermont provide a mechanism for buffering the influence of the RGGI. Vermont has little by way of fossil fuel generation that will require emissions credits.

Vermont is also buffered from exposure to wholesale markets and RGGI through embedded resources and contracts. These contracts protect Vermont from most of the potential cost impacts of RGGI. In the mean time, Vermont can benefit from the program by directing its share of funds to consumers and projects that are consistent with the goals of RGGI. On a regional basis, Vermont should join other states in the region to ensure the success of the RGGI initiative and its goals.

Report Pursuant to Act 61 Section 10.(a)(3)

Obstacles and Opportunities for Creating a System of Energy Efficiency Credits Analogous to Renewable Energy Credits in Vermont

Introduction

Act 61 requires the Department to report on the potential for establishing a system of tradable energy efficiency credits. This potential system would be analogous to a system of tradable credits for renewable resources that exists in much of New England.

The Department engaged the service of LaCapra Associates to assist in the review of this the potential credits sytem. The La Capra analysis includes a review of tradable energy efficiency credit programs currently being developed in Connecticut and Pennsylvania.

There are several reasons for considering a system of tradable energy efficiency credits. . A system of tradable energy efficiency credits holds the potential to stimulate innovative delivery of energy efficiency by more than a single delivery system (i.e., delivery systems that are different from the Vermont Energy Efficiency Utility model and reliance purely on market mechanisms). A tradable credit program could also serve as an additional and flexible source of funding, provided the demand for credits was established through some obligation on load serving entities or consumers.

Tradable energy efficiency credits appear to work best in an environment where renewable energy credits are already in place. All of the states that are considering the use of tradable energy efficiency credits are working from an existing program that utilizes some form of tradable *renewable* energy credits (RECs). By having such a program, key administrative components are already in place, and having such a system creates an opportunity for trading between efficiency and renewables. No such system is in place in Vermont and we are not recommending the establishment of such a program at this time. At this point, we do not anticipate creating a renewable portfolio standard until a later date (current law contemplates the establishment of such as standard in roughly 2013).

The use of a tradable energy efficiency credits is currently under development in Connecticut and Pennsylvania. Hawaii considering this approach.

Because energy efficiency differs in fundamental ways from renewable energy; there are many issues of detail and design that need to be addressed. While we believe that these challenges and details can be worked through, we conclude that Vermont would do well to build upon the experience of other states before committing to such an approach. There is considerable administrative burden that appears to be associated with the development of a system of tradeable energy credits. In the event that Vermont chooses to proceed with such a program, we recommend that it be crafted narrowly to allow for a measured analysis of the program before expanding.

Goals for Tradable Efficiency Credits

There appears to be two potential reasons for considering tradable efficiency credits. Like RECs, energy efficiency credits can stimulate innovative by allowing more than a single delivery system (i.e., stimulating alternatives to the Vermont Energy Efficiency Utility model).[35] Credits could be awarded in a way that would stimulate delivery by different efficiency service providers. Such a system might also yield some direct cost savings because of the potential for competition among providers.

Second, the efficiency credit structure offers promise of an additional and flexible source of potential funding (and cost back to the consumer) through electric rates and/or through resource neutral sales of credits (accompanied by utility obligations to meet a portion of their resource needs through a portfolio requirement). Reliance on a system of tradable credits for energy efficiency could supplement or replace a portion of the existing programs funding mechanisms.

Principles of Tradeable Credits

A system for trading energy efficiency credits (EECs) is similar, in principle, to a system for trading renewable energy credits.

Tradable renewable energy credits (RECs) help correct for the information problem and subsequent allocation inefficiencies of the wholesale power market. Prior to the wholesale market reforms, when utilities in the region generally owned the sources of generation, it was relatively east to identify fuel sources/generation methods affiliated with a given power contract. However, in today's wholesale market, utilities and generation are separate entities. Energy contracts often represent an amalgamation of sources often packages by companies that may not even be utilities. As such, it is not easy to differentiate what electric power cam from renewables versus fossil fuels, etc. Without this information, consumers/states cannot express their preferences for renewables and make efficient choices. By creating a separate market for renewable energy, consumers can state their preference for the attributes of renewable resources (these attributes may include low emissions) from generation sources such as renewables, thus influencing their development.

Demand for RECs were created through the establishment of renewable portfolio standard requirements.[36] The RPS, in essence, created the demand necessary to establish a functioning market for RECs. The establishment of attribute tracking systems in these states enabled an accounting framework separate from the electricity market, to ensure

[35] Examples include self-appointed delivery of energy efficiency where any consumer or third party could apply for certification or credits, or the registry of several qualifying prequalified providers.
[36] "Portfolio" requirements are requirements mandated by state law or regulation to maintain a certain balance of renewable resources in the mix of a load serving entities resources.

that attributes for a single MWh were unique (i.e., there was no double counting) and properly credited. In New England, this accounting framework required the establishment of the New England Generation Information System (GIS). Each of the states in the region uses the GIS system to track the creation and trading of environmental attributes and associated unique products (i.e., RECs). These attributes and products are used to satisfy multiple mandated environmental and renewable energy standards in the region. The GIS system relies on individual generation meters or self-reporting for maintaining accurate records of generation performance.

Relationship Between a System of Tradable Efficiency Credits and a Market for RECs

The establishment of an Energy Efficiency Credit System (EEC) in Vermont would likely be more costly than in other jurisdictions due to Vermont's size and the absence of an existing RPS. . States that are moving in the direction of establishing an EEC typically have an RPS to build upon.

A market for Energy Efficiency Credits would require Vermont to set a target for energy efficiency as a share of the state's total load. However, the benefits provided by an EEC over and above the state's existing energy efficiency programs is unclear, given Vermont's current utility environment. Vermont has an existing mechanism that appears to be efficient relative to neighboring jurisdictions.[37] Establishing an alternative mechanism holds the potential for additional delivery mechanisms. Nevertheless it may come at a cost of less efficient delivery if alternatives stimulate "cream skimming". Multiple delivery systems may also add new costs. For a state as small as Vermont, this could compromise existing program delivery efficiency.

Key Issues to Address

The principle challenge to the establishment of a credit award structure are: (1) ensuring that savings claims are valid and unique; and (2) ensuring that the system works in a way that enhances, not undermines, the existing program.

Achieving both of these criteria could potentially create a burdensome administrative environment. Accounting for the efficiency savings also presents problems.
Other issues include the following design and technical issues.

Design Issues

- Which energy efficiency and demand response categories should be included? There are numerous programs related to energy efficiency which may present tracking and measurement problems.

[37] A comparison of different state programs generally suggest that Vermont's program delivery system is relatively efficient.

- <u>Which customer classes should be included?</u> Each customer class has different rate structures and incentive programs related to energy efficiency.

- <u>Should the programs be limited to those located within the state?</u> Currently, New England RPS states allow RECs from any state as long as the energy is delivered into NEPOOL and the resource qualifies. This allows the most economical resources to be implemented first, irrespective of location. However, energy efficiency programs have a large impact on on the local utilities and administering the programs would be difficult beyond the reach of the state, so an in-state requirement may be necessary. Connecticut has decided on an in-state requirement.

- <u>Will alternative compliance payments (ACP) be required as penalties for non-compliance? If so, what level should the ACP be set at?</u> Some RPS states have set high ACP levels, resulting in high credit prices in times of short supply.

- <u>How will utilities recover the costs associated with buying the credits?</u> Similar to several RPS programs, utilities are permitted full cost recovery for prudent purchases of credits or payment of ACP.

- <u>What if utilities implement the programs themselves? How will credits be allocated between customer and utility? Who earns the credits and thus receive the benefits associated with the credits?</u> Depending on the funding mechanism of the programs and other overlapping funding sources, credits may be allocated to the customer, supplier of the program, utility, or funding administrator (System Benefits Charge administrator).

<u>Technical Issues</u>

- <u>What rules, protocols, standards, and measures are to be used in determining the level of credits associated with each measure?</u> The program administrator will have to establish clearly defined reference levels and/or protocols for all eligible energy efficiency improvements.

- <u>What is an appropriate reference level?</u> Net efficiency impact in this context (also sometimes referred to as additionality) is the difference between the energy use of a more energy-efficient technology and a reference level (naturally occurring or expected level) of energy efficiency and technology. For retrofit and replacement applications, the reference level is generally the technology being replaced or upgraded. For new purchases and applications, the reference level might be the applicable standard or code. Establishing an acceptable reference level can be difficult, especially for energy systems and entire new buildings or facilities.

- o <u>How should depreciation be incorporated into the net energy savings?</u> Certain EE measures may have declining benefit in the future or existing programs that want to receive credit for the remainder of their measure life.

- o <u>How should each measure be certified and audited?</u> This may involve some self-regulation by the customer and sample auditing by technical staff. Alternatively, each measure and customer may need to be tracked by an outside entity.

- o <u>During implementation, should the rules and measures be in the form of a manual with a list of standard efficiency calculations or guidelines for measuring and calculating certain resources?</u> This can simplify or add complexity to the programs, but in either case, clear standards will allow more participation.

- o <u>Once the level of credits for each program are determined, the tracking and movement of the credits also comes into question. Should the EEC be incorporated into the regional attribute tracking system or should a separate system be created?</u> Since most energy efficiency measures are behind-the-meter, the details are not tracked by the RTO. However, existing systems, such as NEPOOL-GIS and PJM-GATS, both allow for self-reporting for non-grid connected resources.

<u>Status of the Energy Efficiency Credit System in Other States</u>

<u>*Pennsylvania*</u>

In Pennsylvania, Governor Edward Rendell signed the Alternative Energy Portfolio Standards Act ("AEPS") into law on Nov. 30, 2004, that establishes certain portfolio requirements including requirements for efficiency. [38] Act 213 took effect on Feb. 28, 2005. Under the AEPS, credits from energy efficiency programs count toward the State's Alternative Energy Portfolio Standards ("AEPS") Tier II requirements.

The energy efficiency credits will compete in the market with credits from the generation of electricity using Tier II resources, including large-scale hydro, municipal solid waste, and integrated combined coal gasification technology. The requirement begins at 4.2% of generation from renewables for the first four years and increases to over 10% in the fifteenth year and beyond.

The Act requires the Commission to propose rules that will enable the participation of demand side management ("DSM"), energy efficiency and load management resources in the alternative energy market. As the Commission notes in the Implementing Order:

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[38] Pennsylvania's Alternative Energy Portfolio Standard (AEPS) (SB 1030), enacted on November 30, 2004, requires all load-serving energy companies in Pennsylvania to provide 18% of their electricity using alternative sources by the year 2020. As is the case for several other states' renewables portfolio standard (RPS), including that of neighboring New Jersey, the law provides for a solar set-aside mandating a certain percentage of PV-generated electricity. Database for State Incentives for Renewables (DSIRE).

…. the primary issue for consideration is the means of verifying and tracking the reductions or shifting of electricity consumption by retail customers due to DSM, energy efficiency and load management measures. This is a challenging assignment, and it is noteworthy that Pennsylvania is the only state within the PJM region to include these resources within its alternative energy standard. The Working Group must consider the scope of the savings to be tracked and the most efficient means of measuring the reduction or shifting of electricity consumption by retail customers.[39]

The program also includes combined heat and power (CHP) projects. All customer classes are included. Utilities receive Alternative Energy Credits for ratepayer funded programs. Pennsylvania relies on the use of a "catalogue" approach for savings that cannot be readily metered. A catalogue provides a set of assumed values for the savings for certain standard end use and efficiency measure profiles.

Another major issue for Pennsylvania is deciding who receives the credit. Eligibility appears to be defined broadly.[40]

In Pennsylvania, entities requesting qualification for credits must be certified.

> Eligible entities may submit an application to the Administrator of the Alternative Energy Credits Program requesting a review for qualifying status. The application must be signed by the customer or his representative and be supported by an affidavit or verification.[41]

Further, evaluation plans must be included for certification.

> The application must include a proposed evaluation plan by which the Administrator may evaluate the effectiveness of the DSM or EE measures provided by the installed facilities. All assumptions contained in the proposed evaluation plan should be identified, explained and supported by documentation where possible. The applicant may propose incorporating tracking and evaluation

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[39] Pennsylvania PUC, Implementation Order, Implementation of the Alternative Energy Portfolio Standards Act of 2004, March 23, 2005, Docket No. M-00051865, at 12-13.

[40] "Entities eligible to apply for credits include, but are not limited to: retail customers who have undertaken measures, EDCs' [Electric Distribution Companies] or EGSs'[Gas Service Providers] whose customers are participating in tariffed programs or retail contracts and who, in accordance with the language of the tariff or contract, have acquired the right to any Credits resulting from operations under the tariff or contract; and equipment or service providers who have provided equipment or services to customers pursuant to a contract that gives the provider the right to any Credits resulting from the installation of that equipment or use of the service. All measures that shift load shall be given full credit for kilowatt hours shifted and saved."

Pennsylvania PUC, Implementation of the Alternative Energy Portfolio Standards Act of 2004: Standards for the Participation of Demand Side Management Resources; Sept 29, 2005, Docket No. M-00051865, at 8.

[41] Id, at 8.

> measures using existing data streams currently in use provided that they permit the Administrator to evaluate the program using the reported data.[42]

As currently structured, the program has no geographic limits on the savings, almost any form of energy efficiency appears eligible for credits, and almost any customer can apply for credits. Given the broad and open nature of the Pennsylvania program, especially as other generation resources are eligible in the Tier II category, it appears likely that the value of eligible credits will be low. Due to the open ended nature of the program, it also appears that the program may incur high administrative costs to cover certification of eligible credit recipients and to provide assurance of real savings.

Connecticut

As part of Connecticut's Act Concerning Energy Independence (Public Act No. 05-1), the state included a separate Class III Resource requirement consisting of CHP and energy conservation programs, in addition to the its existing Renewable Portfolio Standard. Many details of the plan still need to be worked through , but preliminary recommendations should be issued by February 1, 2006. Connecticut has an Energy Conservation Load Management (ECLM) program that is already funded through a system benefits charge analogous to Vermont's Energy Efficiency Charge. At this stage, it is unclear how the credits and revenues allocated to the ECLM will to treated in relation to existing funding sources. Connecticut's statute allows for an allocation of credits between customers and the ECLM, with the load serving entities having ultimate responsibility for meeting the RPS.

The Connecticut model is different from the Pennsylvania model in several ways. Under the Connecticut model, the Class III resource includes only efficiency programs and CHP, while Pennsylvania has a much broader resource group. Also, resources must reside at industrial and commercial customers sites within the state. Credits are also to be allocated between customers and the ECLM. The detailed rules and tracking system have not yet been established.

Conclusions

EEC programs are so new, there is little practical experience other jurisdictions can provide Vermont at this time. . The key issues of feasibility depends on the goals for the program. If the program is merely an effort to realize additional funding for the EEU, then it appears to offer no real advantage over the existing energy efficiency charge, and raises many fundamental challenges associated with allocating the credits to institutions that are already ratepayer funded.

If the goal is to expand the opportunity for alternative sources of delivery, then further investigation may be warranted. Program development should be conducted as a limited experiment designed to foster the development of competitive delivery systems in a way

[42] Id.

that fundamentally does not undermine the effectiveness of Vermont's current delivery system.

Because energy efficiency differs in fundamental ways from renewable energy; there are many issues of detail and design that need to be addressed. While we believe that these challenges and details can be worked through, we conclude that Vermont would do well to build upon the experience of other states before committing to such an approach. It remains unclear whether such a system offers any real advantages to Vermont over the present Energy Efficiency Utility.

We conclude that an EEC system seems unlikely to benefit Vermont for at least four reasons. First, the mechanism is new and appears challenging, especially given the myriad of options that must be considered to administer the program. The states that are moving in this direction are still in the formative stages of planning and implementation and thus provide little guidance. Second, Vermont's size raises fundamental questions about whether it can cost-effectively supply multiple delivery systems, and/or funding sources. Third, Vermont lacks some of the typical prerequisites for an EEC, most importantly, an existing RPS. Fourth, the establishment of an EEC may create new challenges for the current delivery system, by potentially adding new service providers.

Report Pursuant to Act 61 Section 10.(a)(4)

Policy Options facing Vermont in the event a System of Tradable Carbon Emission Allowances is Established in the Region

Introduction

Act 61 included a requirement that the Department evaluate the establishment of a system of tradable carbon emissions allowances, in the region. On December 6, 2005, the Governor announced the signing of a regional pact to reduce greenhouse gas emissions, known as the Regional Greenhouse Gas Initiative (RGGI). This program seeks to reduce greenhouse gas emissions through the use of a tradable carbon emissions program. The program will begin to take effect in 2009. Other states that signed this agreement include: New York, New Hampshire, Maine, Connecticut, Delaware and New Jersey. RGGI will require that emissions from the region's electric power sector be capped at 121 million tons per year.

The cap would remain in place until 2015 when emissions would be lowered incrementally over a four-year period to achieve a 10 percent reduction by 2019.

Key Provisions of the Regional Greenhouse Gas Initiative

The agreement reached among the states includes a number of key provisions reflecting Vermont's policy priorities. These include the following:

1. Use of Emissions Allowances

Each state has the freedom to allocate its emission allowance as it determines appropriate, except that 25% of the allowances will be allocated for consumer benefit or strategic energy purposes. As described in the Memorandum of Understanding among the states,

> Consumer benefit or strategic energy purposes include the use of the allowances to promote energy efficiency, to directly mitigate electricity ratepayer impacts, to promote renewable or non-carbon-emitting energy technologies, to stimulate or reward investment in the development of innovative carbon emissions abatement technologies with significant carbon reduction potential, and/or to fund administration of this Program

2. Establishment of Offsets

The RGGI permits a certain level of emissions offsets that may be used for compliance purposes where reductions in greenhouse gases can be achieved from outside the regulated sector. Specific eligibility requirements and categories are listed in the Memorandum of Understanding and include forestation, landfill methane recapture, and methane recapture from farm operations. Under normal conditions, each generator is allowed to use offsets to cover up to 3.3% of its emissions.

3. Managing Price Impacts through the Use of Offsets

The program can also help to ensure that the ultimate cost to consumers is contained through an offset mechanism. In response to certain price thresholds being breached, the level of offsets and the geographic reach of offsets will be reset to help ensure that the price of the allowances and the program remain within the boundaries of projections. If the price of allowances rises above $7.00 per ton, offsets may cover up to 5% of emissions. If the price rises above $10 per ton, offsets would be expanded to cover up to 20% of emissions.

4. Demonstrated Compliance, Early Reduction Credits, Banking, 2012 Review

Electric generators will be required to demonstrate compliance over a three year period. Within the three years, however, these generators are not required to remain within the boundaries of attainment in any given period.

Each state may grant early reduction credits for projects undertaken after the signing of the MOU, but prior to 2009.

The banking of allowances, offset allowances and early reduction credits is permitted without any restrictions.

States are required to monitor the progress of the program and to hold a comprehensive review of the program in 2012.

Current Status of Greenhouse Emissions by Large Generators in Vermont

The RGGI program applies only to greenhouse gas sources of emissions that are at a threshold size of 25 MW or greater. Biomass generation like McNeil appear to be largely exempt by virtue of the nature of the generator.[43] Of the remaining utility generation in Vermont, there is little by way of significant carbon emitting generation.

Most of the fossil fuel generation in Vermont and owned by Vermont utilities is associated with peaker units that typically run between 200 and 500 hours per year. In total these units sum to about 130 MW. Only one Vermont generator is of sufficient size to be counted in the calculations of RGGI emissions, the Berlin GT (gas turbine) peaking unit at about 56 MW. McNeil, by virtue of its size, would qualify if it ran on a fossil fuel source instead of biomass. A list of the utility-owned fossil fuel generators includes the following.

[43] While biomass from generators like McNeil emit CO_2, they rely on source fuel that is typically replentished by additional biomass resources. When combusted, closed-loop biomass generation releases an amount of carbon dioxide that is less than or approximately equal to the level of carbon dioxide absorbed by the biomass fuel during its growing cycle

Table 1
Vermont Fossil Fuel Generation

Vt. Peaking	MWs
Ascutney G.T.	14.7
St. Albans Diesel	2.4
Berlin A&B G.T.	56.3
Gorge G.T.	15.2
Essex Diesels	4.2
Vergennes Diesels	4.2
Burlington G.T.	23.9
Hardwick Diesel	0.6
Enosburg Diesel	0.9
Barton Diesels	1.5
Rutland 5 G.T.	14.1
Florence Cogen A	4.4
Florence Cogen B	4.4
TOTAL INSTATE OIL & GAS	146.7

Policy Options/Considerations for Vermont

The MOU contemplates that the individual states will be responsible for the administration of state programs that conform to the RGGI. A model rule is under development that will provide recommendations for addressing key policy issues through the rule. Most states, including Vermont, do not appear to require legislation to implement the rule.

Among the policy considerations now and into the future, as the Vermont program is developed and evolves, are its scope and purpose. At present, the RGGI is designed narrowly to focus large electric generation (over 25 MW) within the electricity sector within the Northeast region. Over time, the RGGI program could expand in the range of sectors covered, its geographic scope, and could interact with cap-and-trade structures in other jurisdictions. At this time, the provisions of the MOU require only that Vermont approve rules that conform to the minimum standards established in the MOU.

Administration of the program and the detailed mechanism for allocating credits for ratepayer benefit remains open issues. The Public Service Board either directly or through an agent appears best positioned to administer program distribution responsibilities to ensure ratepayer benefit.

Under RGGI, Vermont would be provided with allowances equal to roughly 1.2 million tons of emissions. While the value of allowances is highly speculative at this point, a range of $1 to $3 per ton has been utilized by the member states under base case assumptions.[44] Therefore Vermont could anticipate seeing $1.2 to $3.6 million in revenues each year if all of the allowances allocated to us are sold. As noted above, the RGGI requires that only 25 percent of the allowances fund initiatives that are directed toward a consumer benefit.

Vermont is in a fairly unique position with respect to RGGI. Vermont enjoys the position of having little by way of eligible emissions. Vermont is also unique in that its utilities have remained vertically integrated. While the Department expects the state's utilities to remain vertically integrated for he foreseeable future, we cannot be so sure that it will continue to have a large portion of it energy needs produced from clean sources. For this reason, it would be prudent for the state to set aside some portion of its RGGI emission allowances as a hedge.

With few competing demands for the use of emission allowances, they an be used to help ensure that Vermont consumers are buffered from the impacts of RGGI related price increases. One important rationale for signing onto the RGGI compact was the recognition that the cost of allowances would be bid into wholesale electricity prices, whether Vermont joined or not. Participation by Vermont creates an opportunity to both further regional goals with respect to emissions, while protecting Vermont ratepayers. The effect on ratepayers of increasing wholesale prices can be buffered relatively easily by directing either the allowances or revenue from their sale back to Vermont's integrated utilities and thus produce lower rates. Alternatively, the value of allowances can be used to help fund the efficiency utility programs or programs that provide similar ratepayer benefits.

The use of the money collected from the allowances should be used in ways that are consistent with the goals of the RGGI. As a matter of principal the funds should be directed toward ratepayers in the most expeditious way possible. Any other use of RGGI funds not directly allocated to ratepayers should be expended in ways that reflect a high value to ratepayers. Load serving entities may be required to establish plans or compete for the use of these funds that are also consistent with the goals of the RGGI. Funds may also be directed toward ratepayer funded efforts like efficiency programs.

<u>Next Steps</u>

- Region will need to establish rules that can be used as a template by individual states (expected March 2006).

[44] http://www.rggi.org/docs/2637,5,MA Power Price Changes (from Standard and High Emission Reference Cases)

- Vermont should adopt a rule or legislation that conforms to the requirements of the template, sometime during 2006/2007 (note that legislation is not required in Vermont to implement).
- Rule and the RGGI program goes into effect on January 1, 2009.

Report Pursuant to Act 61 Section 10.(a)(5)

Options Being Considered by Vermont's Retail Electricity Providers and Transmission Companies for Meeting Vermont's Electric Supply Requirements in Light of the Expiration of Long-Term Supply Contracts.

Introduction

In the 2005 legislative session, the Vermont General Assembly passed Act 61 which, among other things, asked the Department of Public Service to report on the options being considered by Vermont's retail electricity providers and transmission companies for replacing their long-term supply contracts. These contracts are set to begin expiring in the year 2010. This report summarizes the actions of the DPS to answer that question.

While we often look at Vermont's power needs in terms of statewide values, it is important to remember that decisions about Vermont's future power supply requirements will be made by 21 individual distribution utilities, each focusing on their own specific circumstances. Today and for some time now, the state has in aggregate, relied upon long-term contracts for its electric supply. Nevertheless, many utilities—especially the smaller ones---have the majority of their power supply needs covered through relatively short term contracts.

A common theme found in he plans and goals of the utilities is greater resource diversity. Vermont utilities are actively pursuing greater diversity in: fuel sources, contract types, contract lengths, start and end dates, and in the size of resource contracts in proportion to load. Vermont utilities are using more diverse resource portfolios to limit their exposure to the uncertainties of the marketplace.

Current Planning Efforts

There are a handful of planning efforts underway at the utility and state levels. Some of these are ongoing, including the integrated resource plans required of Vermont's distribution utilities. The Public Service Board (Board) is also involved with Vermont's electric companies in a broader integrated planning process for bulk transmission. The fundamental goal of this investigation is to ensure that transmission planning processes give adequate consideration to non-transmission alternatives.

Vermont's electric distribution companies are also working together in a multi-utility collaborative known as "E-23". Among the issues being considered is the replacement of major power contracts (subject of this report).

Following Act 61, the Board is now working with Vermont's utilities and stakeholders to consider increasing the budget of the Energy Efficiency Utility (EEU). In March/April of

2006, the Board will be reviewing the budget for the EEU for the end of 2006. Act 61 also proposed the outline of the SPEED program. The Board, the Department, the utilities and interveners are working at developing rules and procedures to ensure that the goals of that program are met in a way that adds value to Vermont's resource portfolio.

Finally, the Department of Public Service is working with the Vermont utilities and various stakeholders in an innovative collaborative known as "Mediated Modeling – Participatory Energy Planning".[45] We anticipate that this project will provide preliminary recommendations for the replacement of the current long-term contracts.in a format that will provide a baseline for a broader public discussion about our electricity energy future. We anticipate that this process will be followed with broader public outreach efforts that include deliberative polling and public forums.

Background on Vermont's relationship to the Regional Wholesale Market for Electricity

Vermont's electric energy sector remains vertically integrated and price regulated. This is in contrast to most of the northeastern states that have competitive retail markets and retail choice. One reason for moving toward retail choice was to free customers located in the service area of a particular utility from the obligations associated with the power supply decisions of that utility. With retail choice, a customer is free to choose among various suppliers and receives neither the benefits or costs associate with that supplier's power portfolio, but instead pays a market based price. In the short time these markets have been operating in New England, the Department has seen periods when Vermont's committed portfolio compared favorably to the market approach and times when it did not.

The wholesale market in which Vermont utilities operate is a competitive marketplace. The "Standard Market Design ("SMD") adopted by the ISO-New England achieves economic efficiency by having suppliers bid their resources into the market. The intersection of the supply and demand curves sets the price at which all successful bidders are compensated. This means that for Vermont utilities with dispatchable facilities in their portfolio, such as the McNeil plant in Burlington or the StonyBrook combined cycle facility in Massachusetts, in order for them to run, their fuel costs and operational characteristics must be competitive with other plants in New England. If they "clear" and are dispatched, any difference between the clearing price and the operating costs can be used to offset capital or other utility costs.

If the resource is a must run unit or contract, such as Vermont Yankee, the Hydro Quebec VJO contract, or many of the "strip" contracts available on the market today, the owners of the contract receive the clearing price for the contract during its hours of scheduled operation. During hours when the clearing price is higher than the contract price, revenue is generated which can offset other power costs. During hours when the clearing price is lower than the contract price, utility revenues must be used to make up

[45] A window to the process and progress through the project can be found at the Department's web site, http://www.publicservice.vermont.gov/planning/mediatedmodeling.html.

the difference. If a contract can be operated such that the clearing price it receives is greater than the cost of the contract, it is said to be “below market”. If the revenues are less than costs, the contract is said to be “above market”.

The third step in this market process is that each utility must purchase enough energy to serve its customers. The price of this energy is set as part of the same bidding process which created the above prices. Each price is also adjusted to reflect the costs of the marginal losses imposed by the load injected or removed at each node. Prices are also adjusted to reflect the incremental costs resulting from congestion on the network caused by the inability of the transmission system to deliver the lowest cost power to a particular region. The price at which energy is sold into the market is determined by the locational price of the node at which it is delivered and can be different for each resource. The price at which energy is purchased from the market, or the Vermont zonal price, is the same for the entire state and is the weighted average of the nodal prices during each hour.

Bills for power purchased and payments for power delivered are settled on an hourly basis, using average prices for each hour as developed through bidding. If the bid strategy and profile of committed contracts results in additional energy being sold into the market in any hour, any revenue in excess of costs, can be used to offset purchases in any hours when energy sold into the market is less than the demand for energy from the customers of the utility.

Current Status of Committed Energy Supply for the 21 Retail Electric Utilities

Each of the 21 retail electric distribution utilities is responsible for procuring power to serve all of the customers in its service territory. This portfolio has evolved over time as resource options become available and are retired from the portfolio. This has resulted in each utility having a unique power supply portfolio, and somewhat different needs as additional pieces of the portfolio need to be added.

This report examines what Vermont’s utilities are considering to add to their portfolios in 2012 and 2016 when the Vermont Yankee and Hydro-Quebec contracts end. While these two events are certainly significant in terms of making additions to the overall portfolio of Vermont, many utilities are already in a situation where they need additional resources to achieve a balanced portfolio and to hedge themselves against the uncertainty of the market.

It is difficult for a utility of any size to have a portfolio of “owned resources” or contracts which exactly matches its load. As a result utilities generally must rely on the market to balance its needs for power as load and committed supply varies throughout the day, week, month and year. One way to examine the overall market exposure of a utility would be to examine its needs for energy and capacity compared to its committed supply of those products. Performing this comparison over a year ignores hourly and daily market exchange and provides a broad look a utility’s position in each market.

The following chart shows the timetable of resource needs for Vermont utilities. The date is determined to be the point at which a utility's projected needs fall below 85% of its committed products on an annual basis.

Several groupings fall out of this table. On the energy side, there are a number of utilities which are in immediate need of energy. All the utilities except CVPS, GMP, Morrisville and Swanton face immediate needs for a significant portion of their energy requirements. CVPS, GMP and Morrisville have sufficient committed energy to serve their energy needs until the expiration of the Vermont Yankee long-term contract. Swanton receives much of their energy from their owned hydro plant which has surplus capacity for several years and continues to supply much of their needs over the planning horizon.

Looking at capacity, a different picture emerges. Over half of the utilities need some capacity resources prior to 2010. CVPS, GMP, VEC and Enosburg experience needs around 2012. Barton and Swanton have sufficient supplies to meet their needs through 2015.

Timetable of Resource Needs for Vermont Utilities

	Energy	Capacity	Annual Sales (MWh)
BARTON	2007	2016	15,000
BURLINGTON	2005	2010	350,000
CVPS	2013	2012	2,200,000
ENOSBURG FALLS	2007	2012	22,000
GMP	2012	2012	1,930,000
HARDWICK	2007	2008	31,300
HYDE PARK	2007	2010	11,800
JACKSONVILLE	2007	2010	5,700
JOHNSON	2007	2009	15,500
LUDLOW	2007	2009	46,000
LYNDONVILLE	2007	2010	68,000
MORRISVILLE	2013	2013	45,000
NORTHFIELD	2007	2010	27,000
ORLEANS	2007	2010	14,000
READSBORO	2007	2010	2,400
ROCHESTER			6,300
STOWE	2007	2009	60,000
SWANTON	2015	2015	60,000
VEC.	2007	2013	460,000
VT.MARBLE			208,000
WEC	2005	2005	66,000

* Date at which utilities committed resources fall below 85% of needs

Risk Profile of Various Options

Broadly speaking, options being considered by Vermont utilities fall into two categories - owning new resources or engaging in contracts for needed products. The chart below demonstrates the risk profile of various options.

Ownership Type	Risk	Reward
Merchant	Low	Low
Contract	Limited	Limited
Ownership	High	100%

A merchant plant, not owned or under contract to a utility, poses very little price risk to a utility. When needed, it may supply energy to the grid which is transacted at the prevailing market price. Since there is no contract, there is no risk to any utility or ratepayer. Conversely, if the resource is less expensive than the market, those benefits flow to the plant owner and ratepayers have no claim on them.

The risks and rewards associated with a contract are limited to the term of the contract. Vermont's experience with the Hydro-Quebec contract demonstrates how much the reward profile of along-term contract can vary over its life. The Vermont Yankee contract started to show benefits almost immediately, while many of the Independent Power Producer contracts may never be competitive with a market price.[46] Shorter term contracts generally have a lower risk than longer contracts since the signatories have better information about the near term than the longer term. However, like a weather forecast, both long term and short term projections can be wrong.

Ownership poses the highest risks and the greatest potential rewards. Once capital is invested in a plant, it must be repaid, whether he plant produces enough savings to justify its costs, or not. However, ownership benefits (or costs) are not limited by the terms of a contract, but continue for as long as the plant remains in operation.

Options for Additional Committed Supply

Unit Purchases

With this type of transaction, a purchaser buys a specific fraction of the output of a specific facility. The cost of these purchases has both a variable and a fixed component. For a dispatchable type plant the variable charge typically reflects the unit's fuel costs or a floating price designed to reflect the unit's variable cost. The fixed cost component is typically reflective of the seller's fixed costs (capital recovery, taxes, etc.). This type of arrangement allows the purchaser to lock in (fixed cost) part of the cost of power while the fuel component floats (variable cost) with the market.

[46] IPP contracts are alegacy of the federal PURPA legislation where utilities are obligated to purchase power from small generators.

An advantage of a dispatchable unit is that it can be operated only at times when it is economically attractive to do so. This type of unit purchase allows smaller utilities to gain economies of scale by participating in plants which are larger than their needs. The primary drawback to this type of arrangement are that they do not lock in the price of fuel. Purchasers remain exposed to the volatility of the primary fuel of the unit. They are also unit contingent. This means that power is only available when the unit is dispatched. Contractual, price or emission limits may restrict operating times of various units. Purchasers of small amounts of a unit do not control its bidding protocol or other decisions about maintenance or operation of the unit.

Spot Purchases –
The ISO-New England markets offer products in both the Real time and Day Ahead markets which effectively act as a fallback resource to sell surplus energy or to buy short term energy needs. The advantage to the spot market is its flexibility. You only buy or sell what you need with no advance commitment. The drawback is that the price is not known until the time of delivery. Too heavy a reliance on spot purchases can cause unacceptable fluctuation in power costs, resulting in frequent rate investigations. Generally speaking, utilities seek to minimize the percentage of power purchased in the spot market.

Bilateral Strip Purchases –
This option represents energy only (without capacity), purchased at a fixed price for a specified term and delivered to the New England hub. Because of the large amount of these transactions in the New England market and the fact that they are traded in standard blocks of 25 MW for peak and off peak periods, brokers are able to post daily prices for these products. An advantage to these types of contracts is that, since they are standard terms and sizes, they can be arranged with minimal transaction costs. Since these are block purchases for every hour in the day, it is difficult to match load expectations to the load profile of a utility. Although limited on/off peak flexibility is possible, this type of purchase represents an imperfect fit relative to the load curve of a utility. In the wake of the various financial problems in the power industry, attention has focused on bilateral contract terms that guarantee the financial performance of the parties. . These constraints can place significant credit and performance requirements on the buyer and seller. If forward prices decline so that the forward contract price is higher than e prevailing market price, a buyer is required to guarantee its performance under the contract with a a letter of credit or performance bond. Utilities in a stronger financial position and thus better positioned to post letters of credit, etc., will have less stringent requirements imposed on them.

System Power Purchases

This type of contract, similar to the current Hydro-Quebec arrangement, requires a purchaser to pay for specific amounts of energy in defined periods. Contracts can be structured based on a fixed or variable price. Pricing for this type of power would likely reflect prevailing market conditions at the time of the signing. Depending on the desires of the parties, part of the contract can be structured in a dispatchable fashion so that it is purchased only when it is economic to do so. A disadvantage of this type of contract is that someone must assume the risk of fuel price volatility. The purchaser can do this by paying a premium for a fixed price or the seller can do it by making the contract only dispatch, under certain conditions.

Renewable generation projects-

Vermont Landfill Gas – Landfill gas offers several advantages because it uses a renewable fuel and produces no net emissions. Landfill gas developments can fulfill requirements under the Massachusetts and Connecticut RPS laws as well as contributing to the SPEED requirements of Act 61 in Vermont. They provide base load power and in Vermont can be sized appropria tely for small utilities. Landfill gas projects are generally easier to permit than other types of generation. The opportunity for landfill gas is limited by the finite number of sites available and the scale requirements for a site to be feasible. The Washington Electric Coop has developed a 3.5 MW station in Coventry which has expansion possibilities for the future. BED is able to derive some supply from a 560 kW generator at the Burlington landfill. However, this source is expected to expire in approximately 2009 and BED does not list any new landfill gas projects to replace it. The Vermont Public Power Authority has researched its landfill gas options and to date not found any feasible sites. However, in a related endeavor it is working with Agri-Mark and others to develop a farm methane site in East Middlebury. There are also a few small LFG projects, both operating and proposed, by independent power producers.

Vermont Wind - Wind has a number of advantages including the fact that it is renewable and has no air emissions. Wind is eligible for the SPEED program as well as RPS programs in New England states. Wind can be built in sizes which are suitable for Vermont sized utilities. Wind also tends to be more prevalent in the high energy demand winter months. It has the potential to provide low cost power to those municipal and Cooperative utilities whose low capital costs could put them at a financial advantage over other developers. The drawbacks to wind include the fact that it is an intermittent supply and that, at present, it is uncertain if a project can be successfully permitted in Vermont. Presently, Green Mountain Power (GMP) is operating a 6 MW wind facility in Searsburg and they have plans to partner with a private developer to install another 33 MW as well. GMP would subscribe for about one-third of this facility's production. Other utilities with plans for wind projects include: Vermont Public Power Authority's East Mountain site and the Vermont Electric Co-op's (VEC) East Haven project. According to VEC, this project is fully subscribed. VEC also has received a grant from the United States Department of Energy to help develop an additional 1.5 MW of wind energy.

Peaking units -- Peaking units can provide a hedge against high market prices. These units units are relatively low in cost and are designed to operate for only a few hundred hours per year at times when prices are very high. They have low fixed costs relative to load generating facilities and relatively high va riable costs. These units can be located in many places because of their compact size. However, their emissions characteristics limited the number of hours they can run in a year.

The drawback to peaking units is that they are not very efficient. New technology has improved over existing units, but they are still much less efficient that a comparable combined cycle unit. Because of this characteristic, they will only be economic to operate during times of high prices.

VPPSA is currently examining the feasibility of constructing a modest sized (40 MW) peaking plant in the Swanton area. It would be fueled by natural gas. GMP is replacing its Gorge peaking unit and is considering whether to increase its size in response to any expressed needs of Vermont utilities.

Energy Efficiency

Energy efficiency has been and will continue to be an important tool for meeting Vermont's supply needs. Efficiency Vermont assumed responsibility for core energy efficiency programs from the individual utilites—except Burlington Electric Department--in 2000. Discussions are ongoing regarding the appropriate budget levels for Efficiency Vermont and the resulting impacts of DSM will be factored into any plans for future supply needs.

Financial risk management and hedging

With the introduction of a competitive wholesale electric market, various types of financial instruments common to other commodity type markets have appeared. These instruments, in conjunction with an active trading arena and effective price discovery, has resulted in an array of techniques to protect an energy supplier from market fluctuations. However, like any insurance policy, they come at a price and may offer protection against a situation which never arises. Utility managers are gaining experience with these resources and have begun to use them more frequently as the situation demands. Several types are discussed below

Collars – A collar limits the price of an item to a specific range. If the price goes above a negotiated level, the purchaser only pays up to the contract maximum. If the price falls below a preset level, the purchaser continues to pay the minimum price specified in the contract. If the price remains between the contract collars, the purchaser pays that (market) price.

Laddered contracts – laddering of contracts refers to the timing of purchases. If a supplier is facing a deficit in future supply, rather than trying to out guess the market, smaller contracts are purchased at different times to cover the need. For example, a 15 MW supply can be structured as three separate 5 MW contracts.

GMP has a relationship with Morgan Stanley which effectively hedges their market exposure for most of their expected load throughout the year.

Examples of Portfolios

The attached charts show the current and projected positions of the individual Vermont utilities. As discussed above, since this tally is done on an annual basis, it ignores the hourly buying and selling into the market which takes place every day.

Vermont Public Power Supply Authority (VPPSA) – In 1999 VPPSA undertook a comprehensive study of generation options. From this study, they identified two potential sited for generation in Vermont. They are continuing to evaluate a Franklin County site as a potential location for a natural gas fueled generator. Additionally, VPPSA has investigated generation projects using wind, landfill methane and farm methane. The incentives created by the SPEED program will likely help the economics of these renewable installations.

Central Vermont Public Service Corporation (CVPS) – In the near term, CVPS completed a sale of most of its excess energy in order to stabilize its costs going forward. In their 2003 integrated resource plan ("IRP"), they examined a strategy of replacing existing resources with a range of alternatives and a scenario where those resources were retained for the duration of their contracts. Their conclusions were that the sale and replacement of resources was unwarranted and that there is time to develop a strategy to replace those resources when their contracts expire.

Green Mountain Power (GMP) – GMP is looking at a set of strategies which include contracts, construction of a peaking plant, spot market purchases and a combination of renewable resources. Their preferred strategy is to pursue a contract based portfolio in conjunction with ownership of additional peaking resources. However, their plan notes that a sustained shift to higher market prices driven by fossil fuel prices could render renewable resources a superior choice to the bilateral contract strategy.

Burlington Electric Department (BED) - is currently facing market exposure for some of its load. To cover their position, BED is working to develop renewable resources through a 20 year contract with Endless Energy for the output of a proposed wind project in Manchester Vermont. BED plans to use short term market purchases to cover its interim power gap.

Washington ElectricCooperative (WEC) -- has developed the Coventry landfill gas project to cover most of its near term needs. This project is expandable as the landfill increases and should provide a stable resource for them in the coming years.

Vermont Electric Company (VEC) - is looking to develop a mix of wind and landfill gas resources. They are also looking at CHP and have one small project in development and another in process. In the near term, they are looking at a series of contracts, developed over time, each several years in duration, to achieve "dollar price averaging" so that market conditions at any one time do not account for the entire portfolio, but rather an average of prevailing conditions are present. They also see ownership of a peaking plant as a hedge against high hourly price spikes.

The Vermont utilities see the value of diversity in their resource portfolios. In order to allow time to develop instate renewable or peaking resources, most are relying on a market based strategy for the short to medium term.

Summary and Conclusions

The Contracts between Vermont utilities and Vermont Yankee, and the contact between the Vermont Joint Owners and Hydro-Quebec represent the two largest sources of power and are due to expire over the coming decade. These two contracts provide roughly two-thirds of our energy needs. The Vermont Yankee contract expires in 2012 and the bulk of the Hydro-Quebec contract expires in 2015.

Despite the focus given these two contracts, the resource needs of individual utilities vary significantly among the utilities. There are 21 distribution utilities in Vermont with resources and contracts that vary considerably. Only CVPS and GMP currently have contracts with Vermont Yankee. Many of the smaller utilities, including Burlington, Vermont Electric Cooperative, and many of the municipal utilities fact the potential for significant resource needs in the next 2 years. Planning efforts to address their needs are well underway.

There are a number of planning efforts underway to help address Vermont's long term resource needs. Many of these planning efforts were stimulated by Act 61 and efforts to revisit the funding of the efficiency utility, stimulate contracts with instate renewable generations, and establish more open and public planning processes for meeting needs for delivery of reliable electric service through transmission planning.

As listed above, the planning activities among the individual utilities vary depending according to their resource needs. Increasingly, the very nature of resources that are available to utilities has changed. Many of the smaller public utilities appear to be focusing their planning efforts on longer term resource commitments.

As the state looks toward the replacement of major resources such as Vermont Yankee and Hydro-Quebec, Vermont's investor-owned utilities appear to be largely looking toward the market for the replacement of their embedded resource mix. Greater reliance on the market comes with greater flexibility, but also carries with it greater consumer exposure the market fluctuations.

Vermont utilities and policy makers may need to forge a stronger consensus around suitable resources given the realities of the current market environment and regulatory environment. The Department of Public Service is working with the utilities and other stakeholders to help foster a broader public consensus around future sources using various participatory planning efforts including the Mediated Modeling effort.